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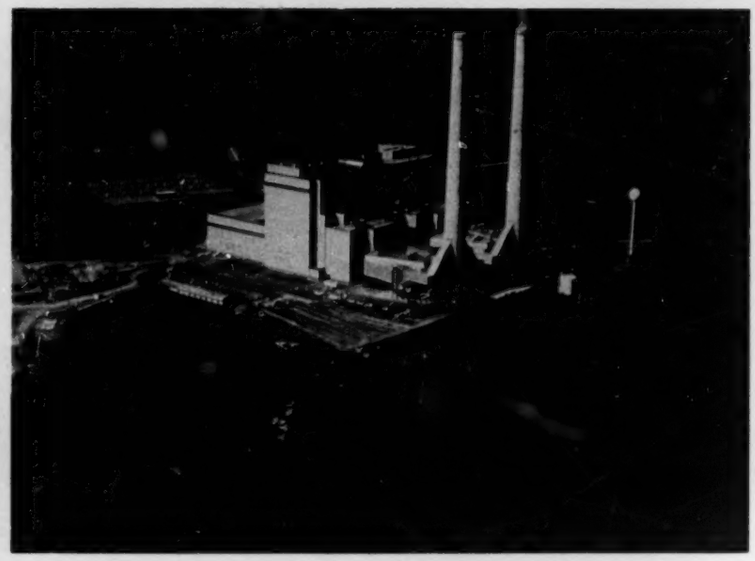

Duke Power's Belews Creek-2 ranks as most efficient unit

Duke Power Company's Belews Creek Unit 2 (at left) was the most efficient fossil-fueled generating unit in the nation in 1986. The unit had a heat rate of 8,913 Btu per kilowatt hour. The utility had six of the top 11 most efficient units in the country, and had the best system heat rate for fossil-fired boilers. To learn the nation's most efficient investor-owned utility and find out where your company ranks, turn to EL&P's Annual Top 100 Operating Performance Report beginning on p.19.

Centerior Energy to sell unit ownership for $1 billion

CLEVELAND—Centerior Energy Corporation announced a refinancing package in June that involves a $1 billion sale and leaseback of Toledo Edison's and Cleveland Electric Illuminating's shares of the Bruce Mansfield coal plant and a portion of the companies' shares of the Beaver Valley 2 nuclear unit.

Rate requests

Centerior Energy, which serves as the parent company for the two utilities, said the plan will enable Edison and CEI to reduce future rate increase requests by at least $35 million a year. No buyers for the generating capacity have yet been found, but a company spokesman said Centerior hoped to have investors lined up before fall. Both plants are located in western Pennsylvania.

The utilities plan to sell all or most of their Mansfield capacity, which totals 764 MW (32%) of the three-unit plant operated by Pennsylvania Power Company.

Companies' shares

The companies' shares of Beaver Valley 2 total 370 MW (44%). The plant is operated by Duquesne Light Company.

Beneficial transaction

Centerior pointed out that the transaction will be beneficial from a rate-making standpoint, because it will minimize the effect of placing the companies' newest nuclear units—Perry 1 and Beaver Valley 2 in rate base.

Beaver Valley 2 recently won Nuclear Regulatory Commission approval to load fuel and conduct low power testing of the unit.

Creative plan

"This is a creative plan that will have a positive effect on our customers and shareowners alike," said Centerior's Senior Vice President-Finance Edgar H. Maugans. "It's the culmination of six months of extremely complex and difficult work by our financial people, and it's a major step toward achieving long-term financial stability."

The sale and leaseback has recently grown in popularity with utilities that are placing costly new generation in

Continued on page 3

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EPRI utility survey identifies major areas of future concern

PALO ALTO, CA—Future power supply, cost and finance concerns, the environment and utility competition are some of the primary issues facing electric utilities, according to the Electric Power Research Institute's Ninth Member Utility Survey. (See chart.)

EPRI compiled survey responses from 109 of the 548 EPRI member utilities. The institute said it uses the results of the poll to aid in preparing its strategic plan.

Power supply important

The survey found that future power supply is seen by the members as a very important long-term issue. Concerns related to power supply, such as reducing costs, environmental worries and end use were viewed as having high potential resolution through research, development and demonstration (RD&D).

Issues like finance, deregulation, competition and nuclear plant licensing were seen as having a low potential to be resolved through RD&D.

As for utility RD&D needs, the survey respondents identified clean coal, environmental control, demand-side planning, utility planning methods, system interconnections and operations and acid rain.

Future demand plans

Most of the companies said they plan to meet future electricity demand primarily from existing generation, life extension and purchasing power from other utilities. (See chart on p.7).

Questioned about their investment

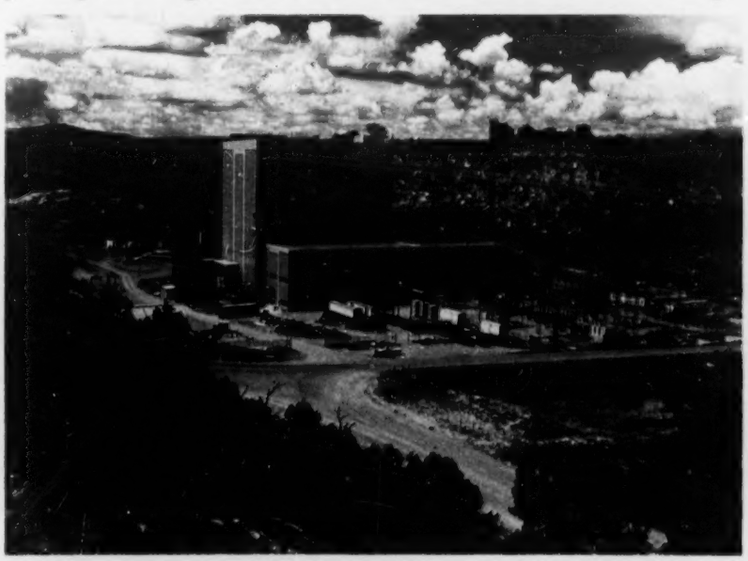
Continued on page 7

SIGNIFICANT CURRENT UTILITY ISSUES

Category	Percent of First-Order Responses
Cost and Finance	21
Power Supply and Resources	19
End Use and Marketing	17
Environment	12
Competition and Deregulation	11
Transmission and Distribution	6
Regulatory	4
Planning	3
Other:	7
	100
Public Relations	
Theft	
Corporate Culture	
Education	
Etc.	

(Source: Ninth EPRI Member Utility Survey, May 1987)

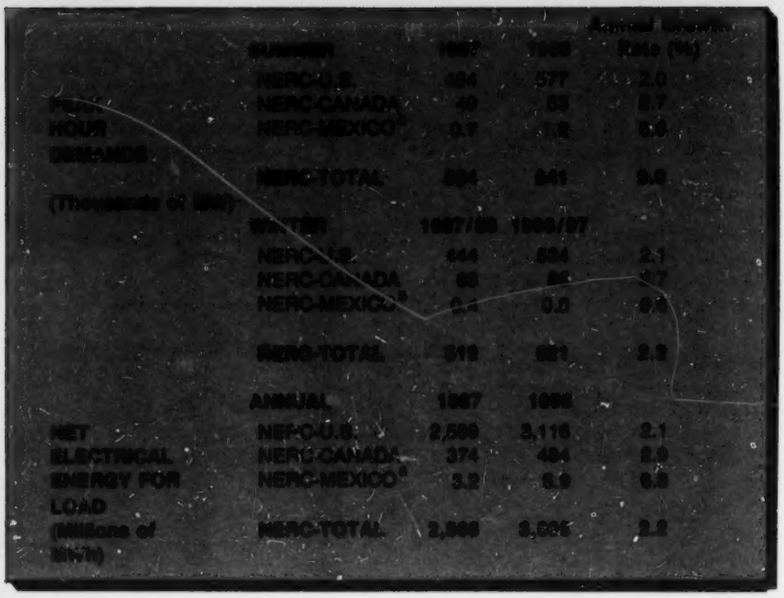
Colorado-Ute's utility-scale CFB project generates first electricity



Colorado-Ute Electric Association's 110 MW Nucla circulating fluidized-bed combustion plant began producing power in June. The utility says the $100 million plant is the first utility-scale power plant using CFB technology. Major retrofitting of the 27-year-old plant began in May 1985. "The CFB technology we are using at Nucla station has great significance for the electric industry and for our customers," said Ted Rosiak, Colorado-Ute's vice president in charge of thermal generation. "Perhaps the single most important characteristic of the plant's technology is the promise it holds as a long-term, cost-effective solution to the acid rain issue." The Nucla demonstration project is being funded by 23 organizations, with no government support.

SUMMARY OF 1987-1996 NERC PROJECTIONS

DEMAND



SUPPLY

				Annual Growth
	SUMMER	**1987**	**1996**	**Rate (%)**
	NERC-U.S.	647	716	1.1
	NERC-CANADA	86	97	1.4
PLANNED CAPACITY RESOURCES (Thousands of MW)	NERC-MEXICO[a]	0.8	1.2	4.5
	NERC-TOTAL	**734**	**814**	**1.2**
	WINTER	**1987/88**	**1996/97**	
	NERC-U.S.	668	727	1.0
	NERC-CANADA	87	101	1.5
	NERC-MEXICO[a]	0.8	1.2	4.5
	NERC-TOTAL	**756**	**829**	**1.0**

[a] *Includes only that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.*

(Source: "1987 Electricity Supply & Demand", North American Electric Reliability Council)

NERC issues peak projections

According to the North American Electric Reliability Council, there are no major differences in its latest projections compared to those made in 1986. NERC said growth rates for peak demand and annual energy are slightly lower than those made a year earlier. To serve anticipated demands, NERC said utility systems are planning to increase their net capacity resources by about 80,000 MW over the 1987-1996 period, an average annual growth rate of 1.2 percent. The information comes from an advance release of NERC's annual Electricity Supply & Demand report. A more detailed version of the report will be published later this summer.

Boston Edison wants to cut large customer demand by 20 percent

BOSTON—Boston Edison launched an ambitious energy conservation and load management program in June that has been designed to reduce by 20 percent the energy consumption and on-peak demand of its 1,500 largest customers.

Under its "Design Plus" program, the utility is encouraging its largest commercial and industrial customers to permit design teams to evaluate their electrical use and propose state-of-the-art equipment and systems aimed at reducing the demand for electricity.

Boston Edison will subsidize the design costs and up to half of the installation costs to retrofit the latest technologies in energy-efficient lighting, HVAC, control and other electric systems over the next three years.

Ten customers

Ten of the company's eligible customers will be asked to participate in the initial phase of the program this year. The remaining eligible customers will be invited to participate on a first-come-first-serve basis between 1988 and the end of 1990 and will be notified of their eligibility by Dec. 31 of this year.

Sensational

"We think this is a sensational way to save energy and help our customers enhance the value of their facilities," said Craig Peffer, Boston Edison vice president, commercial. "It's a program that's sure to grab the attention of our biggest customers."

According to the utility, the first 10 customers will provide an estimated total demand savings of slightly more that 2 MW and an annual savings of nearly 8,500 megawatthours.

Boston Edison said customer benefits will include design and contract administration services, up to 50 percent of hardware and installation costs, the latest advances in energy efficient technologies and substantial savings in their electric bills.

Oglethorpe to take over project

ATLANTA—The managements of Georgia Power Company and Oglethorpe Power Corporation have agreed in principle to form a joint venture covering the ownership and and operation of the partially completed 847-MW Rocky Mountain pumped storage hydro project.

Under the agreement, Oglethorpe would assume construction and operation responsibilities and would own approximately 74 percent of the facility. The exact ownership shares would be determined based on Oglethorpe's cost of completing the plant, compared with Georgia Power's investment prior to the closing.

Construction of the facility was launched in 1978, but nine years later it still is only 15 percent complete.

F.F. Stacy, Oglethorpe president and chief executive officer, estimated that between $600- and $700-million will be required to complete the project. Completion currently is set for 1996.

Robert W. Scherer, Georgia Power chairman, cited the agreement as "another example of the state's power suppliers working together to benefit electric consumers.

"We view the proposed agreement as a continuation of our efforts to ensure a reliable supply of electricity for Georgia's future." Georgia Power and Oglethorpe have cooperated with each other since 1975.

Stacy praised the proposed agreement as being mutually beneficial and said it will provide peak electric power to Oglethorpe's 39 rural cooperatives during a period of great anticipated need. He said that the co-ops' peak demand is expected to grow by about four percent annually over the next ten years.

Although managements of both organizations have signed the letter of intent, a final agreement still must be developed and approved by their boards of directors. Further, regulatory approval will be required.

Once the agreement is reached Oglethorpe Power could begin to assume responsibility for the completion of the facility.

Centerior Energy to sell . . . from page 1

service. (See chart.)

Cost-cutting measures

Since merging one year ago, the companies have implemented a series of cost-cutting measures. The utilities will save $25 million annually through an early retirement program. Savings from combining operations functions will total $20 million per year.

Maugans said these and other cost efficiencies made possible by the affiliation are now expected to surpass the $90 million in annual savings anticipated at the time of the affiliation.

MAJOR SALE-LEASEBACK TRANSACTIONS

Buyer	Seller and Plant Involved	Price
Not yet determined	Centerior Energy Corporation (Bruce Mansfield coal plant and Beaver Valley 2 nuclear unit)*	$1 billion (approximate)
Emerson Electric, IBM, Philip Morris	Tucson Electric Power Co. (Springerville coal plant)	$850 million
Shell Leasing	Deseret Generation (Bonanza coal plant)	$664 million
Beatrice Financing Services, Chrysler Financial, Dart & Kraft Financial, First Chicago Leasing, J.C. Penney, Saks	Basin Electric Power Cooperative (Antelope Valley coal station unit 2)	$623 million
Group of Investors (Owner Trustee, First National Bank of Boston)	Ohio Edison (Perry nuclear plant unit 1)	$509 million
Public offering	El Paso Electric (Palo Verde nuclear plant)	$396 million
Chrysler Financial, Ford Motor Credit, HEI Investment, IBM	Oglethorpe Power (Scherer coal plant unit 2)	$395 million
Chrysler Capital, Drexel Burnham Leasing, Mellon Financial Services	Public Service of New Mexico (Palo Verde nuclear plant unit 1)	$325 million
Drexel Burnham Leasing, General Electric Credit, Shell Leasing	Montana Power (Colstrip coal plant unit 4)	$292 million
General Electric Credit	Portland General Electric (Boardman coal plant)	$233 million

* *Two-part transaction*

Sources: Business Week, Public Utilities Fortnightly, The Wall Street Journal, Centerior Energy Corporation.

Nader group offers nuclear shutdown strategies

WASHINGTON—Public Citizen, the consumer and environmental organization founded by Ralph Nader, has released a report outlining strategies for citizen groups to use in their efforts to close nuclear power plants.

Entitled *Shutdown Strategies: Citizen Efforts to Close Nuclear Power Plants*, the report cites several citizen efforts aimed at closing commercial nuclear reactors.

Public Citizen said citizens are becoming more assertive at the state and local levels as they attempt to have plants closed for economic, safety, environmental and health reasons.

"Growing evidence that a Chernobyl-scale accident could happen in the U.S., the increasing accumulation of radioactive waste that nobody wants, and rate shock that consumers cannot afford, have prompted a resurgence of grass roots activism against nuclear power," said the report's author Joseph Kriesberg.

The report cites state ballot measures pending that could result in the shutdown of the Maine Yankee plant, Rancho Seco plant, the Pilgrim and Rowe units, and the Trojan reactor.

In addition to offering examples of current efforts to close plants, the report reviews eight strategies being used by nuclear activists. They are:

1.) requesting a formal analysis of the economic impact of closing a particular reactor;
2.) intervening before state public utility commissions;
3.) advocating state least-cost electrical planning;
4.) translating concern over nuclear waste into support for closing reactors;
5.) opposing inadequate emergency evacuation planning;
6.) increasing state and local regulatory authority over nuclear safety;
7.) organizing ballot measure campaigns; and
8.) pushing for public power systems.

For each strategy, Public Citizen includes four to nine case studies which summarize efforts at particular plants where that strategy has been or is being used. One or more contact names are also listed in the report.

Copies of the report are available for $25 from Public Citizen, 215 Pennsylvania Ave. SE, Washington, D.C. 20003, (202) 546-4996.

Nuclear waste disposal fees "adequate"

WASHINGTON—The Department of Energy says the fee it collects to pay for radioactive waste disposal is adequate and that no change in the rate is needed at this time.

DOE charges nuclear utilities one mill per kWh of nuclear-generated electricity to cover the federal government's costs for developing the disposal system for spent nuclear fuel and high-level radioactive waste.

The estimated cost of the disposal system is between $28.4- and $38.2-billion in 1986 dollars.

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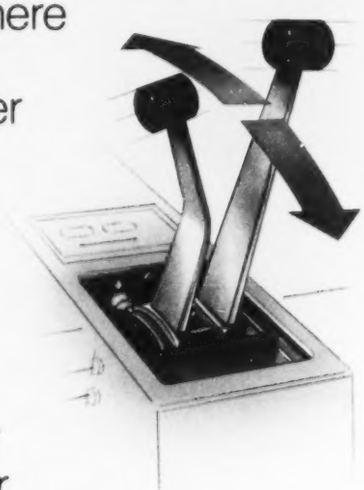

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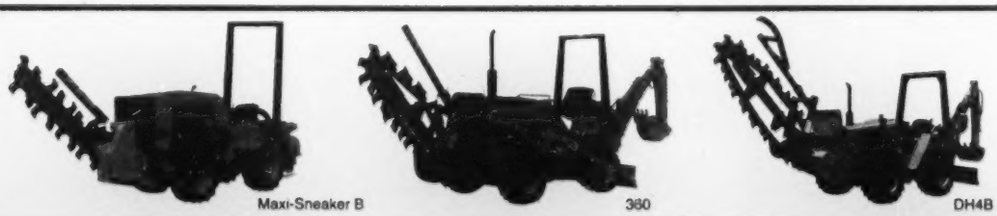

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Inquire R.S. 2

EPRI survey . . .

from page 1

plans, the respondents said that much of their capital expenditures during the next five years will be spent on finishing plant construction, building new distribution lines, extending plant life and building new transmission substations.

MEETING DEMAND (Normalized to 100%)

Means	1986-1995	1996-2005
Existing Generation (includes life extension)	58%	48%
Buy from other utilities	28	29
New Generation		
Conventional	4	7
Advanced	1	4
Demand-Side Management	5	6
Buy from Cogenerators, etc.	3	4
Uncommitted as yet	1	2

(Source: Ninth EPRI Member Utility Survey, May 1987)

Cited as likely envirnomental "problem" issues were PCBs, acid rain, hazardous waste disposal, leaking underground storage tanks and transmission right-of-way siting.

Strategic plan emphasis

EPRI asked the utilities where its strategic program emphasis should be placed. Respondents ranked highest the Environmental Assessment, Environmental Control Technology, and Fossil Fuel Power Plants programs. Demand-side Planning and Distribution strategic programs rose significantly from the previous survey, while Environmental Assessment, Transmission, and Plant Electrical Systems and Equipment strategic programs rose somewhat from the last survey.

For more information

All the survey results were analyzed on a national and a regional basis. For more information, or a copy of the survey (Special Report P5160-SR), contact EPRI at (415) 855-2000.

Peak demand periods can be forecast faster and more accurately

Steve R. Shelton
ElectriCities of North Carolina

Keith S. Henry
Southern Engineering

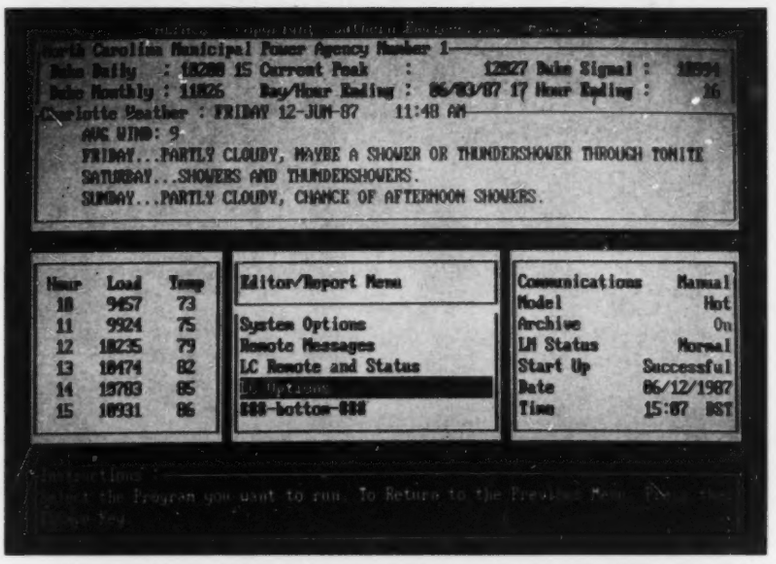
In the rolling hills of piedmont North Carolina, a new load management system is being tested that is enabling those municipal utilities that own and operate their own electric distribution systems to access load management information using personal computers.

The system saves municipalities both time and money by quickly forecasting and communicating peak demand periods.

The load management program is a computer-based information system that helps municipal employees make decisions by providing relevant data in an easily understandable form. The system accesses a database to locate the necessary information, uses mathematical or statistical models, and produces the desired decision-support information at the user's terminal. It can be used as an analytical tool or can be combined with an "expert system" for a more automated operation.

Fifty-one of North Carolina's "electric cities" are participants in two power supply agencies. The power agencies contract for a range of technical and management services through ElectriCities of North Carolina, Inc., a joint municipal assistance agency based in Raleigh.

North Carolina Municipal Power Agency Number 1 (NCMPA 1) serves 19 piedmont North Carolina municipalities, while the North Carolina Eastern Municipal Power Agency (NCEMPA) provides service to 32 eastern North Carolina cities and towns.


Carolina Municipal Power Agency Number 1
Duke Daily : 18200 15 Current Peak : 12827 Duke Signal :
Duke Monthly : 11826 Day/Hour Ending : 06/03/87 17 Hour Ending : 16
Charlotte Weather : FRIDAY 12-JUN-87 11:48 AM
AVG WIND: 9
FRIDAY...PARTLY CLOUDY, MAYBE A SHOWER OR THUNDERSHOWER THROUGH TONITE
SATURDAY...SHOWERS AND THUNDERSHOWERS.
SUNDAY...PARTLY CLOUDY, CHANCE OF AFTERNOON SHOWERS.
Hour Load Temp
10 9457 73
11 9924 75
12 10235 79
13 10474 82
14 10783 85
15 10931 86
Editor/Report Menu
System Options
Remote Messages
LC Remote and Status
Communications Manual
Modem Hot
Archive On
LM Status Normal
Start Up Successful
Date 06/12/1987
Time 15:07 EST

The main screen shows a variety of information, such as previous peak, projected peak, current load, and weather data. Menu is bottom center of screen.

Baseload for NCMPA 1 consumers is supplied by its 75 percent ownership share of Unit 2 of the Catawba Nuclear station constructed by Duke Power Company. NCEMPA has a similar joint ownership arrangement with Carolina Power & Light Company and five generating units.

Demand charges

Within the NCMPA 1 service area, the demand charges for each municipality are based upon its load during the hour of the Duke system monthly peak. Before July 1983 all 19 cities were on a wholesale rate that contained a 30-minute billing demand for each delivery point.

Now the cities can consolidate their efforts to predict the monthly one hour peak of a much larger system. If the peak hour can be accurately predicted, load management periods can be minimized, resulting in greater load reductions and less customer inconvenience.

NCMPA 1 officials relied on historical data combined with intuitive guesses to determine the monthly peak in the past. The new system produces a more accurate forecast and will allow the cities to access load management information at their convenience.

The agency wanted a system which could collect and maintain data, forecast future hourly loads, display the data in color graphics, and determine the optimal hours to load manage and communicate the information to participating cities. NCMPA 1 could not justify purchasing a centralized SCADA system. So, it contracted with Southern Engineering to build such a system.

It is now completed and six cities are connected to the system. NCMPA 1 anticipates that within the year a total of 10 or 12 of the 19 municipalities will purchase the hardware and begin to use the system.

Convenient accessing

"The convenience of accessing load forecasting information is valuable in the management of our load control system," said Lloyd Shank, Electric Utility Director of High Point. "The system helps us to make better use of our time and provides us with data that otherwise would have cost us a small fortune to obtain."

NCMPA 1 expects to save more than $1.5 million this year through its load management activities. It plans to concentrate on improving the system by evaluating the model and weather forecasts, determining the accuracy of the analog signal as compared with edited billing data, and by testing different load control parameters in the load control logic.

In addition, access to a weather radar system is being considered in order to track thunderstorms across the service area as they develop. NCEMPA, the sister power agency, is also working to install a similar system for its own use that will soon be in operation.

The new NCMPA 1 system consists

Continued on page 16

Summer residential electric bills slightly higher in '86, says survey

WASHINGTON—The nationwide average cost for electricity last summer for residential customers was 8.3 cents per kilowatt hour, according to a survey taken by the National Association of Regulatory Utility Commissioners.

The survey found that typical summer residential bills in 1986 varied by almost 400 percent depending upon the area of the country. NARUC said customers in Ontario, Oregon paid about 3.9 cents per kWh, while customers in New York City paid 14.8 cents per kWh. (See table.)

NARUC's seventh annual survey contains bill comparisons for the largest service territories of the major investor-owned regulated electric utilities. A total of 194 service areas were surveyed. Bills for residential electric service for the months of June, July and August were reported to NARUC for three different levels of energy consumption—250-kWh, 500-kWh, and 750-kWh. Also reported were typical levels of electricity use for customers with central air conditioning.

Bills vary little from 1985

According to the organization, the report shows that residential bills have remained virtually unchanged over the bills reported in 1985. Using the 500-kWh per month level as a comparison, NARUC pointed out that the nationwide average cost of electricity rose from 8.2 cents per kWh in 1985 to 8.3 cents per kWh in 1986.

The study shows that in 14 service areas, consumers are paying 11 cents or more per kWh, while in 21 service territories customers pay less than 6 cents per kWh.

Those five companies with the most expensive service territories are: Consolidated Edison, Commonwealth Edison, Long Island Lighting,. Orange & Rockland Utilities, and San Diego Gas & Electric.

Utilities with the least expensive service areas include: Idaho Power (Ontario, OR), Pacific Power & Light, Washington Water Power (Spokane, WA), Washington Water Power (Lewiston, ID), and Idaho Power (Boise, ID).

For copies

Copies of the 205-pp. report can be obtained for $16.50 each from NARUC, P.O. Box 684, Washington, D.C. 20044.

TEN MOST EXPENSIVE SERVICE TERRITORIES

Company	City	State	500 KWH Jun	500 KWH Jul	500 KWH Aug	Total Bill	Avg. Cost Cents/KWH	Nation Rank
Consolidated Edison Co. of N.Y.	New York	New York	$74.38	$75.33	$72.69	$222.40	$0.148	1
Commonwealth Edison Co.	Chicago	Illinois	$71.41	$71.62	$72.87	$215.90	$0.144	2
Long Island Lighting Co.	Long Beach	New York	$64.82	$62.84	$63.11	$190.77	$0.127	3
Orange & Rockland Utilities, Inc.	Middletown	New York	$63.54	$61.47	$60.04	$185.05	$0.123	4
San Diego Gas & Electric Co.	San Diego	California	$59.97	$59.97	$59.97	$179.91	$0.120	5
Public Service Elec. & Gas. Co.	Newark	New Jersey	$58.72	$58.72	$58.72	$176.16	$0.117	6
Philadelphia Electric Co.	Philadelphia	Pennsylvania	$57.58	$58.81	$58.81	$175.20	$0.117	7
Iowa-Illinois Gas & Elec. Co.	Rock Island	Illinois	$58.12	$57.82	$57.48	$173.42	$0.116	8
Kauai Electric Co.	Lihue	Hawaii	$60.17	$56.66	$54.11	$170.94	$0.114	9
Hawaii Electric Light Co.	Hilo	Hawaii	$58.33	$56.86	$54.42	$169.61	$0.113	10

TEN LEAST EXPENSIVE SERVICE TERRITORIES

Company	City	State	500 KWH June	500 KWH Jul	500 KWH Aug	Total Bill	Avg. Cost Cents/KWH	Nation Rank
Idaho Power Co.	Ontario	Oregon	$19.26	$19.26	$19.26	$57.78	$0.039	194
Pacific Power & Light Co.	Yakima	Washington	$19.52	$19.52	$19.52	$58.56	$0.039	193
Washington Water Power Co.	Spokane	Washington	$19.99	$19.99	$19.99	$59.97	$0.040	192
Washington Water Power Co.	Lewiston	Idaho	$20.02	$20.02	$20.02	$60.06	$0.040	191
Idaho Power Co.	Boise	Idaho	$20.90	$20.90	$20.97	$62.77	$0.042	190
Montana Power Co.	Billings	Montana	$21.39	$21.39	$21.39	$64.17	$0.043	189
CP National Corp.	La Grande	Oregon	$22.12	$22.12	$22.12	$66.36	$0.044	188
Pacific Power & Light Co.	Kalispell	Montana	$23.35	$23.35	$23.37	$70.07	$0.047	187
Portland General Elec. Co.	Portland	Oregon	$24.12	$24.12	$24.12	$72.36	$0.048	186
Pacific Power & Light Co.	Portland	Oregon	$26.19	$26.19	$26.19	$78.57	$0.052	185

(Source: NARUC 1986 Summer Survey of Residential Electric Bills)

THE TOP 100 electric utilities' 1986 operating performances

Don Minner
Associate Editor

Coal usage dropped slightly in 1986... oil usage rose substantially...gas usage was lower...peak demands and reserve margins barely grew...and, generating capacity increased only slightly during the year.

These are some of the highlights of *EL&P's* annual review of 1986 operating data from the nation's 100 largest investor-owned utilities. The information is taken from their Uniform Statistical Reports. Individual utility data are shown on the large tables on the following pages and summaries can be found in the smaller tables.

Fossil fuel consumption changes are highlighted in Table 1. Coal usage for the Top 100 dipped 1.5 percent in 1986 to 509 million tons, from 1985's 517 million tons.

According to the National Coal Association, all U.S. electric utilities are expected to use 694 million tons of coal in 1987. Coal's share of the generation market is predicted to be 55.3 percent, down from its approximate 56 percent share in 1986. It was about 56 percent in 1985, also.

NCA said only 2.1 gigawatts of new coal-fired capacity will come on-line in 1987, compared to 8.8 gigawatts of new nuclear capacity. Overall, forecasts the association, electricity generation is expected to rise 2 percent this year.

Slightly lower growth will be experienced in the traditionally coal-based industrial Midwest and higher growth rates will occur in New England, the South and Southwest. NCA stated these are regions where competing fuels and available nuclear power make a greater difference in the amount of coal used.

Overall, said NCA, U.S. production of bituminous coal and lignite is forecast to reach a record 897 million tons by year-end, 9 million tons more than in 1986 and 1 million tons above the historic high reached in 1984.

1986 coal use

Here's how the largest coal users in the Top 100 fared in 1986:

○ Southern Company...down 3 percent to 42.7 million tons.
○ American Electric Power...up 0.4 percent to 41.8 million tons.
○ Texas Utilities...up 8 percent to 31.7 million tons.
○ Detroit Edison...up 2 percent to 15.9 million tons.
○ Allegheny Power...down 5 percent to 14.7 million tons.
○ Commonwealth Edison...down 0 02 percent to 13.6 million tons.
○ Central & South West...down 1 percent to 13.0 million tons.
○ Ohio Edison...down 3 percent to 11.1 million tons.
○ Duke Power...up 9 percent to 11.1 million tons, and
○ Public Service of Indiana...up 2 percent to 10.9 million tons.

The Utility Data Institute, a nonprofit information service company in Washington, D.C., recently noted that U.S. electric utilities added 21 new steam-electric power plants to the national grid in 1986, resulting in 16,441 MW of new capacity. Twenty-one hydroelectric, gas turbine, and diesel units totaling 635 MW also were placed in service.

The new steam capacity included 12 new coal-fired plants (7,072 MW) at a cost of about $7 billion. The units were located in Indiana, Kentucky, Louisiana, Montana, North Dakota, Oklahoma, Texas and Utah.

Eight new nuclear plants (9,314 MW) entered commercial operation in 1986 at a cost of $25 billion, said UDI. The units are located in Arizona, California, Connecticut, Louisiana, New Jersey, Pennsylvania, and South Carolina.

Oil usage

Reflecting continued low oil prices, the Top 100 increased its oil consumption by almost 26 percent, to 215 million barrels in 1986. The rise in oil usage stopped a trend of decreases in consumption the previous two years. At a meeting of OPEC oil ministers at the end of June, the group announced an agreement to limit production to 16.6 million barrels of oil per day in the second half of 1987. Analysts say this should boost oil prices by at least one dollar by year's end. OPEC desires to keep oil prices at or above the $18 a barrel price level.

Utilities that showed the largest increases in oil consumption last year (among those that burned at least one million barrels in 1986) were:

○ Middle South Utilities...up 846 percent to 2.2 million barrels.
○ Dominion Resources...up 242 percent to 4.8 million barrels.
○ GPU...up 152 percent to 1.7 million barrels.
○ Detroit Edison...up 107 percent to 1.4 million barrels.
○ Niagara Mohawk Power...up 92 percent to 9.6 million barrels, and
○ Public Service of New Hampshire ...up 92 percent to 4.7 million barrels.

Utilities that had the largest decreases in oil consumption last year (among those that burned at least one million barrels) were:

○ San Diego Gas & Electric...down 141 percent to 2.6 million barrels.
○ Eastern Utilities Associates ...down 119 percent to 5.9 million barrels.
○ Southern California Edison...down 42 percent to 1.3 million barrels.
○ Baltimore Gas & Electric...down 29 percent to 1.4 million barrels, and
○ Public Service Enterprise...down 13 percent to 6.2 million barrels.

TABLE 1
FOSSIL FUEL CONSUMPTION

	1985	Change	1986	Change
Coal (million tons)	517	+8.4%	509	−1.5%
Oil (million bbl)	171	−10.0%	215	+25.7%
Gas (billion cu. ft.)	2,844	−4.3%	2,234	−15.5%

TABLE 2
PEAK DEMAND AND RESERVE MARGINS

	1985	Change	1986	Change
Seasonal Peak (MW)	383,264	+2.8%	385,347	+0.5%
Total System Capability (MW)	461,053	+0.9%	462,259	+2.3%
System Reserve Margin	21.9%		24.5%	
Total Owned Capability (MW)	461,254	+2.8%	462,300	+0.2%
Owned Reserve Margin	17.2%		18.9%	
Average Load Factor	59.9		56.0	

TABLE 3
TYPE OF GENERATION (MW)

Type	1985	Change	1986	Change
Conventional Steam & Combined Cycle	354,880	+4.1%	353,897	−0.3%
Hydro & Pumped Storage	27,897	+13.2%	28,243	+0.9%
Gas Turbines & Internal Combustion	34,258	−0.3%	34,081	−0.6%
Nuclear	58,741	+13.9%	67,027	+14.1%
Total	475,836	+5.4%	483,088	+1.5%

Natural gas use

Natural gas consumption by those surveyed in *EL&P's* report fell 15.5 percent last year. It had decreased in 1985 by four percent.

Utilities with the largest increases in natural gas consumption in 1986 (among those consuming at least one billion cubic feet last year) were:

○ SCANA...up 283 percent to 1.1 billion cubic feet.
○ Southern Company...up 122 percent to 13.5 billion cubic feet.
○ Public Service of Colorado...up 31 percent to 1.7 billion cubic feet, and
○ Gulf States Utilities...up 12 percent to 163.3 billion cubic feet.

Utilities in the Top 100 with the largest decreases in natural gas consumption last year (among those consuming at least one billion cubic feet) were:

○ Delmarva Power & Light...down 83 percent to 1.0 billion cubic feet.
○ Florida Power Corp...down 81 percent to 1.5 billion cubic feet.
○ Boston Edison...down 74 percent to 8.6 billion cubic feet.
○ Northeast Utilities...down 69 percent to 1.5 billion cubic feet, and
○ Tucson Electric Power...down 40 percent to 2.7 billion cubic feet.

Thermal efficiency fell

The large table showing individual company fuel consumption also ranks the Top 100 by system heat rate.

Utility thermal efficiency fell slightly in 1986 for the first time in five years. The median in 1986 was 10,610 Btu/kWh, compared to 10,605 Btu/kWh in 1985. It was 10,616 in 1984, 10,650 in 1983 and 10,790 in 1982.

Among all the Top 100, 43 utilities improved their system heat rates last year, while 55 companies had higher heat rates than in 1985.

For the third consecutive year, Commonwealth Energy was ranked

as the most efficient utility in the nation. Consumers Power Company ranked second in 1986, as it did a year earlier. Toledo Edison jumped from its 15th place rank in 1985 to third in this year's report. Florida Power Corp. moved from 5th to 4th, while American Electric Power dropped to 5th from its 1985 2nd place ranking.

Enough similarities

EL&P feels that although there are many differences among the Top 100 companies, there are enough similarities to make valid comparisons.

The Top 20 most efficient baseloaded generating units in the country as reported in the Uniform Statistical Reports are shown in Table 4. Leaders in fossil-boiler heat rate are listed in Table 5. (The effect on heat rates of nuclear units, gas turbines, and diesel engines is eliminated.)

The top three units in 1986 were the same top three in 1985. Duke Power's Belews Creek-2 headed the list once again, followed by the utility's Marshall-3 and Marshall-4 units. Duke Power had 6 of the 11 most efficient units in the country last year.

Also, Duke Power had the best system heat rate for fossil-fueled boilers in 1986, an honor it held in 1985. The only newcomer to the system heat rate leaders was United Illuminating, which had the 9th most efficient fossil

TABLE 4
TOP GENERATING UNITS — BY HEAT RATE
(CF > 50%)

Unit	Capacity (MW)	Utility	Heat Rate (Btu/KWh)
1. Belews Creek - 2	1,120	Duke Power	8,913
2. Marshall - 3	630	Duke Power	8,976
3. Marshall - 4	630	Duke Power	8,992
4. Belews Creek - 1	1,120	Duke Power	9,094
5. Morgantown - 2	582	Potomac Electric	9,106
6. Allen King - 1	560	Northern States Power	9,113
7. Canal - 1	568	Commonwealth Energy	9,123
8. JH Campbell - 3	719	Consumers Power	9,138
9. Amos - 2	800	American Electric Power	9,146
10. Marshall - 1	385	Duke Power	9,160
11. Marshall - 2	385	Duke Power	9,268
12. Crystal River - 5	717	Florida Power Corp.	9,272
13. Mountaineer - 1	1,300	American Electric Power	9,297
14. Sporn - 5	450	American Electric Power	9,305
15. Crystal River - 4	717	Florida Power Corp.	9,315
16. JH Campbell - 1	265	Consumers Power	9,324
17. Bowen - 4	866	Southern Company	9,344
18. Stuart - 1	228	Cincinnati Gas & Electric	9,364
19. Bay Shore - 1	136	Toledo Edison	9,368
20. Ft. Myers - 2	402	FPL Group	9,400

HEAT RATES AND FUEL CONSUMPTION

Company	Rank	Heat Rate (Btu/KWh)	Up or Down	Coal (1000 tons)	Oil (1000 bbl)	Gas (1000 MCF)	Percent Change in Coal	Oil	Gas
Commonwealth Energy	1	9,739	U	0	7,367	889	—	+ 9	- 87
Consumers Power	2	9,808	D	6,642	632	146	+ 10	+214	- 51
Toledo Edison	3	9,860	D	2,489	2	48	+ 10	- 33	- 38
Florida Power Corp.	4	9,865	D	5,451	10,117°	1,479	+ 8	+ 47	- 81
American Electric Power	5	9,879	D	41,751	0	23	+ 0.4	—	- 4
Duke Power	6	9,881	D	11,135	126	328	+ 9	- 98	+116
Southwestern Public Service	7	9,927	D	6,803	2	28,712	- 3	- 75	- 36
United Illuminating	8	9,934	D	763	5,640	93	- 1	+ 5	+100
Cincinnati Gas & Electric	9	9,941	D	7,492	13	62	+ 1	- 38	- 29
DPL, Inc.	10	9,954	U	5,387	8	14	+ 19	+ 33	+133
New York State Electric & Gas	11	9,959	D	5,334	22	—	- 12	+ 57	—
Allegheny Power	12	10,023	U	14,674	0	0	- 5	—	—
Public Service Indiana	13	10,048	D	10,901	2	0	- 9	—	—
Potomac Electric	14	10,067	D	6,333	4,289	0	+ 3	+ 10	—
Detroit Edison	15	10,080	U	15,930	1,359	12,690	+ 2	+107	+ 20
Central Illinois Light	16	10,094	D	2,091	0	14	- 3	—	+100
Boston Edison	17	10,098	D	0	12,815	8,639	—	+ 91	- 74
Eastern Utilities Associates	18	10,159	D	344	5,877	0	- 33	+119	-100
Southern Company	19	10,162	D	42,696	356	13,515	- 3	+ 98	+122
Washington Water Power	20	10,171	D	1,082	2	9	- 1	—	—
SCANA	21	10,179	U	3,691	4	1,107	- 8	- 60	+283
Central Hudson Gas & Electric	22	10,186	D	0	6,007	553	—	+ 10	- 88
Teco Energy	23	10,196	D	5,745	166	0	- 7	- 76	—
New England Electric	24	10,208	U	2,860	9,872	10	- 4	+ 24	-100
Illinois Power	25	10,266	U	7,744	140	403	+ 1	+115	+ 33
Carolina Power & Light	26	10,328	U	9,451	18	525	+ 1	- 80	- 54
Orange & Rockland	27	10,346	D	0	2,200	15,978	—	+ 66	- 25
Union Electric	28	10,364	U	9,979	83	297	- 2	+246	- 13
Duquesne Light	29	10,375	D	4,769	71	160	+ 3	- 39	+100
Dominion Resources	30	10,386	D	9,139	4,839	285	+ 14	+242	- 78
Midwest Energy □	31	10,393	—	1,923	9	317	—	—	—
Pennsylvania Power & Light †	32	10,407	D	10,162	9,259	0	- 8	+ 24	—
Gulf States Utilities †	32	10,407	D	2,625	442	163,335	- 0.3	+1,063	+ 12
Central & South West	34	10,414	U	12,980	100	254,275	- 1	- 42	- 9
FPL Group	35	10,423	D	2	24,500	122,969	+200	+112	+ 8
Niagara Mohawk Power	36	10,430	D	2,462	9,620	20,960	- 17	+ 92	+ 15
Houston Lighting & Power	37	10,434	U	8,680	124	283,788	- 17	+121	- 14
Cleveland Electric Illuminating	38	10,464	U	6,827	86	0	+ 2	+ 5	—
Wisconsin Power & Light	39	10,480	D	3,773	24	197	+ 4	+ 9	+302
Hawaiian Electric	40	10,492	U	0	11,198	0	—	+ 5	—
Baltimore Gas & Electric	41	10,493	D	4,092	1,419	928	+ 18	- 29	+ 10
Louisville Gas & Electric	42	10,502	D	3,852	0	15	+ 3	—	- 95
Atlantic Electric	43	10,564	U	1,055	1,275	1,687	- 1	+ 10	- 6
Pacific Gas & Electric ø	44	10,571	—	0	2,097	155,522	—	+159	- 41
Idaho Power	45	10,572	U	1,261	1	5	- 59	—	- 76
Utah Power & Light	46	10,578	U	6,419	45	140	- 20	- 48	- 38
El Paso Electric	47	10,592	D	362	0	15,515	+ 27	-100	+ 6
Long Island Lighting	48	10,596	D	0	15,622	24,526	—	- 2	- 13
Savannah Electric	49	10,607	U	852	202	679	- 0.4	+432	+ 45
Kansas City Power & Light	50	10,610	D	5,418	82	217	- 0.1	- 7	- 12
Central Maine Power	51	10,611	U	0	3,071	0	—	+ 29	—
Southern Indiana Gas & Electric	52	10,617	D	2,161	0	152	+ 4	—	- 11
UtiliCorp United	53	10,620	D	1,418	6	60	+ 12	+200	+329
Ohio Edison	54	10,643	U	11,148	62	0	- 3	+182	—
IPALCO †	55	10,659	U	5,071	50	0	+ 5	- 37	—
Northeast Utilities †	55	10,659	D	394	13,662	1,460	+ 3	+ 14	- 69
Central Louisiana Electric	57	10,672	U	396	0	34,102	- 42	—	- 15
Central Illinois Public Service	58	10,686	U	4,735	21	0	- 7	+ 50	—
Northern States Power	59	10,704	U	6,694	94	695	- 11	+194	+ 55
Rochester Gas & Electric	60	10,706	U	527	330	71	- 32	- 33	+ 22
Kentucky Utilities	61	10,722	D	4,962	0	1	+ 3	-100	—
San Diego Gas & Electric	62	10,735	D	NA	2,588	32,280	—	-141	- 25
Delmarva Power & Light †	63	10,736	U	2,666	3,409	1,001	- 3	+ 37	- 83
Iowa-Illinois Gas & Electric †	63	10,736	D	2,447	11	616	+ 30	- 8	+ 2
Southern California Edison †	65	10,739	U	5,251	1,348	186,531	+ 67	- 42	- 32
Public Service Enterprise †	65	10,739	U	3,603	6,160	24,354	- 16	- 13	- 36
Northern Indiana Public Service	67	10,799	D	4,056	28	731	- 6	- 38	- 3
Middle South Utilities	68	10,803	D	8,281	2,166	221,123	+ 6	+846	- 4
Public Service New Hampshire	69	10,809	U	917	4,661	0	- 36	+ 92	—
Iowa Power & Light	70	10,818	D	2,042	23	208	- 1	+ 64	- 49
Sierra Pacific Power	71	10,820	U	848	312	1,425	+ 23	+3,367	- 56
Philadelphia Electric	72	10,836	D	2,437	4,505	452	- 18	- 2	- 56
PacifiCorp	73	10,846	U	10,233	64	—	- 19	- 7	—
Wisconsin Public Service	74	10,883	D	3,322	35	82	+ 9	- 14	+203
Public Service Colorado	75	10,886	U	6,784	29	1,720	+ 2	- 3	+ 31
AZP Group	76	10,901	D	5,536	11	10,039	- 13	- 93	- 39
Central Vermont Public Service	77	10,906	D	24△	60	0	- 72	+ 30	—
Oklahoma Gas & Electric	78	10,912	U	5,830	24	107,292	- 10	+ 20	- 2
Wisconsin Energy	79	10,928	U	6,594	110	674	+ 7	- 24	+174
Texas Utilities Electric	80	10,933	D	31,711	122	364,511	+ 8	- 87	- 9
Puget Sound Power & Light	81	10,936	D	2,498	4	63	+ 9	- 43	+ 2
Consolidated Edison	82	10,970	D	0	17,591	76,511	—	+ 17	- 7
Commonwealth Edison	83	10,977	D	13,647	4,081	3,579	- 0.2	+ 61	- 2
Madison Gas & Electric	84	10,993	U	682	8	941	- 11	+100	+ 20
Empire District Electric	85	10,995	D	1,071	13	248	- 10	+ 86	- 58
Minnesota Power	86	10,996	U	2,891	0	0	- 12	—	—
Kansas Gas & Electric	87	11,001	D	2,703	0	7,244	- 7	-100	- 39
General Public Utilities	88	11,004	U	6,843	1,694	11,088	- 76	+152	- 3
Tucson Electric	89	11,062	U	1,948	0	2,687	- 10	—	- 40
Nevada Power	90	11,067	U	2,420	96	3,365	+ 6	+ 33	+ 0.5
Montana Power	91	11,101	D	3,025	9	412	+ 24	- 64	- 7
Portland General Electric	92	11,118	D	897	4	0	+ 2	+ 75	—
Iowa Electric Light & Power	93	11,212	D	1,018	15	209	+ 9	+ 7	+ 55
Interstate Power	94	11,244	U	1,868	12	794	- 12	- 8	+ 50
Kansas Power & Light	95	11,330	U	5,990	11	1,230	+ 1	- 27	- 4
Public Service New Mexico	96	11,597	U	3,688	21	907	- 13	+200	- 34
Otter Tail Power	97	11,854	U	1,796	3	0	- 10	+ 50	—
Centel	98	12,147	D	905	1	3,885	+ 4	- 67	- 15
MDU Resources	99	12,269	D	1,342	10	8	- 15	+ 25	- 47
TNP Enterprise	100	>20,000	U	0	0	5	—	—	- 29

△ Wood
° Doesn't include heat recovery of 261 MWH
NA Not available
° Includes 18,000 barrels of oil/coal mixture

† Tie
□ 1985 figures, 1986 Not available
ø 1985 Heat rate, other figures preliminary 1986.

PEAK DEMAND AND CAPABILITY

Company	Season Peak MW	% Change	Winter (W) or Summer (S)	Total System Capacity MW (at time of peak)	Total System Reserve %	Owned Capacity MW (at time of peak)	Owned Reserve %	Load Factor %
Allegheny Power System	5,674	- 5.9	W	7,012	24	7,935	40	67.8
American Electric Power	15,555	-23.2	W	22,786	46	22,827	47	64.8
Atlantic Electric	1,459	+ 1.9	S	1,606	10	1,481	2	55.3
AZP Group	3,153	- 1.4	S	3,473	10	3,290	4	53.2
Baltimore Gas & Electric	4,818	+ 5.8	S	5,656	22	5,403	17	58.3
Boston Edison	2,254	-16.0	S	2,874	28	2,708	20	64.8
Carolina Power & Light	7,402	- 1.3	W	8,916	21	8,635	17	57.7
Centel	590	- 2.6	S	NA	NA	663	12	NA
Central & South West	10,243	+ 4.5	S	13,223	29	13,049	27	54.7
Central Hudson Gas & Electric	764	+ 3.4	S	1,047	37	983	29	66.7
Central Illinois Light	866	+ 3.8	S	1,086	25	1,136	31	61.1
Central Illinois Public Service	1,621	- 1.9	S	2,579	59	2,805	73	56.9
Central Louisiana Electric	1,182	+11.0	S	1,708	45	1,681	42	53.4
Central Maine Power	1,453	+ 5.7	W	1,667	15	966	-34	68.4
Central Vermont Public Service	389	- 7.3	W	486	25	94	-76	58.9
Cincinnati Gas & Electric	3,434	+ 3.5	S	4,030	17	4,030	17	57.8
Cleveland Electric Illuminating	3,601	+10.6	S	4,315	20	4,315	20	62.2
Commonwealth Edison	15,100	+13.9	S	19,735	31	19,161	27	53.3
Commonwealth Energy System	757	- 1.9	W	935	24	225	-70	65.0
Consolidated Edison	7,641	- 0.4	S	10,104	32	9,200	20	49.6
Consumers Power	5,127	+ 8.3	S	5,963	16	6,283	23	65.1
Delmarva Power & Light	1,840	+ 5.8	S	2,277	24	2,277	24	63.3
Detroit Edison	8,050	+12.2	S	9,199	14	9,321	16	57.9
Dominion Resources	10,358	+ 0.4	S	12,511	21	11,405	10	58.8
DPL, Inc.	2,247	- 1.0	S	2,651	18	2,651	19	60.4
Duke Power	12,586	- 0.8	W	14,790	18	14,602	16	59.8
Duquesne Light	2,132	+ 0.2	S	2,920	37	2,859	34	60.6
Eastern Utilities Associates	698	- 5.4	S	888	27	587	-16	64.6
El Paso Electric	938	+ 7.0	S	891	-5	1,104	+18	59.9
Empire District Electric	612	+12.7	S	704	15	642	5	48.1
Florida Progress (FPC)	5,977	+ 2.8	W	6,780	13	5,989	0.2	43.3
FPL Group (FP&L)	12,139	- 3.1	W	11,598	-4	14,068	16	54.8
General Public Utilities	6,606	- 1.2	S	9,586	45	7,787	18	NA
Gulf States Utilities	5,089	+0.02	S	7,548	48	6,689	-31	63.5
Hawaiian Electric Industries	1,205	+ 5.1	W	1,535	27	1,489	24	71.2
Houston Industries	10,556	- 0.4	S	13,258	26	11,863	12	57.0
Idaho Power	2,089	- 9.1	S	2,728	31	2,548	22	63.0
IE Industries	954	+ 3.5	S	1,147	20	1,047	10	56.2
Illinois Power	2,949	+ 6.4	S	4,172	42	3,740	27	63.0
Interstate Power	768	+ 4.1	S	953	24	950	24	60.7
Iowa-Illinois Gas & Electric	950	- 1.6	S	1,198	26	1,452	53	52.9
Iowa Resources	1,178	+ 6.1	S	1,389	18	1,141	- 3	49.0
IPALCO	2,191	+ 7.2	S	2,911	33	2,911	33	56.9
Kansas City Power & Light	2,373	+ 6.2	S	2,937	24	2,937	24	48.0
Kansas Gas & Electric	1,604	+ 3.6	S	2,428	51	2,434	52	51.2
Kansas Power & Light	1,844	+ 6.7	S	2,356	28	2,531	37	50.0
Kentucky Utilities	2,406	- 1.9	S	3,375	40	3,130	30	57.5
Long Island Lighting	3,441	+ 1.8	S	NA	NA	NA	NA	NA
Louisville Gas & Electric	1,913	+ 5.6	S	2,312	21	2,312	21	52.1
Madison Gas & Electric	447	+ 9.0	S	599	34	587	31	53.0
MDU Resources Group	338	- 3.4	S	449	33	408	21	59.2
Middle South Utilities	11,697	+ 7.6	S	16,382	40	16,321	40	54.4
Midwest Energy	NA	NA	NA	NA	NA	NA	NA	NA
Minnesota Power	1,026	- 3.1	W	1,482	44	1,240	21	72.0
Montana Power	1,233	- 4.8	W	1,704	36	1,524	24	68.0
Nevada Power	1,661	+ 1.0	S	1,993	20	1,741	5	46.1
New England Electric	3,520	- 1.0	W	4,326	23	3,891	11	64.7
NY State Electric & Gas	2,252	- 1.7	W	3,004	33	2,441	8	66.3
Niagara Mohawk Power	5,724	- 2.4	W	7,803	36	5,320	- 7	67.9
Northeast Utilities	4,242	- 2.3	W	5,487	29	6,223	47	66.0
Northern Indiana Pub. Service	2,324	+ 9.8	S	3,796	63	NA	NA	61.5
Northern States Power	6,012	+15.5	S	6,889	15	6,121	2	56.2
Ohio Edison	4,243	+ 3.9	S	5,588	32	5,402	27	66.2
Oklahoma Gas & Electric	4,614	+ 3.7	S	5,701	37	5,655	23	46.4
Orange & Rockland Utilities	822	+ 4.1	S	1,027	25	1,011	23	51.3
Otter Tail Power	515	- 7.4	W	685	33	598	16	61.4
Pacific Gas & Electric	13,452	- 6.6	S	20,164	50	15,204	13	64.4
PacifiCorp	3,841	- 9.7	W	5,140	34	4,007	4	68.0
Pennsylvania Power & Light	5,154	+ 3.5	W	7,519	46	8,360	62	62.1
Philadelphia Electric	6,135	+ 1.7	S	6,039	-2	7,858	28	58.1
Portland General Electric	2,659	- 8.2	W	4,364	64	2,696	1	61.2
Potomac Electric Power	4,702	+ 0.4	S	5,375	14	5,375	14	53.2
Public Service Enterprise Group	7,735	+ 0.2	S	9,364	21	9,007	16	53.2
Public Service of Colorado	3,150	+ 3.1	S	3,805	21	2,924	- 7	67.7
Public Service of Indiana	3,792	+ 3.2	S	5,881	55	5,627	48	59.6
Public Service of New Hampshire	1,375	+ 1.3	W	1,635	19	1,285	- 7	58.9
Public Service of New Mexico	916	+ 6.4	S	1,536	68	1,442	57	50.1
Puget Sound Power & Light	3,460	- 3.2	W	4,069	18	1,650	-52	53.0
Rochester Gas & Electric	1,100	+ 2.2	S	1,439	31	1,056	- 4	64.7
San Diego Gas & Electric	2,376	+ 1.8	S	3,200	35	2,531	7	58.4
Savannah Electric & Power	485	+13.4	S	620	10	600	6	51.1
SCANA Corp.	2,853	+ 5.5	S	3,870	36	3,890	36	58.0
Sierra Pacific Resources	708	- 0.6	S	921	30	831	17	72.2
Southern California Edison	14,599	+ 0.1	S	18,147	24	14,931	2	57.0
Southern Co.	22,739	+ 6.8	S	24,768	9	25,810	14	57.2
Southern Indiana Gas & Electric	967	+ 7.7	S	1,167	21	1,167	21	59.3
Southwestern Public Service	2,912	+ 1.7	S	4,251	46	4,051	39	62.3
Teco Energy	2,598	- 5.1	W	2,840	9	3,020	+16	52.4
Texas Utilities	16,537	+ 4.0	S	18,854	14	17,804	8	55.1
TNP Enterprises	NA	NA	NA	NA	NA	NA	NA	NA
Toledo Edison	1,423	+ 3.6	S	1,733	22	1,681	18	64.8
Tucson Electric Power	1,151	+ 3.0	S	1,420	23	1,330	16	57.3
Union Electric	6,449	+ 7.5	S	7,622	18	7,698	19	53.8
United Illuminating	990	-10.8	S	1,295	31	1,230	24	59.8
Utah Power & Light	3,110	- 4.6	S	3,168	2	3,202	3	69.4
Utilicorp United	792	+10.3	S	911	15	911	15	44.9
Washington Water Power	1,286	-15.5	W	1,935	51	1,357	6	60.4
Wisconsin Energy	3,810	+ 8.1	S	4,404	16	4,354	14	60.0
Wisconsin Power & Light	1,470	+ 7.2	S	1,959	33	1,901	29	64.3
Wisconsin Public Service	1,293	+ 6.0	S	1,700	32	1,688	31	71.9

NA Not available

system.

In the second large table you will find data, summarized in Table 2, that shows peak demand barely rose in 1986, edging up only 0.5 percent. A summer noted by its coolness and a mild winter across much of the nation last year kept peaks from growing as much as predicted, or in previous years.

Companies recording the greatest peak demand growth were:

- Northern States Power...up 15.5 percent to 6,012 MW.
- Savannah Electric...up 13.4 percent to 565 MW.
- Empire District Electric...up 12.7 percent to 612 MW.
- Detroit Edison...up 12.2 percent to 8,050 MW.
- Central Louisiana Electric...up 11.0 percent to 1,182 MW, and
- Cleveland Electric Illuminating ...up 10.6 percent to 3,601 MW.

The 1986 gains in peak demand were not as large as those made in 1985. The top four utility peak demand leaders in 1985 all had a higher percentage increase than 1986's leader Northern States Power.

Summer peakers in 1986 outnumbered winter peakers 74 to 24. Reflecting the warmer than usual winter, there were 24 winter peaking companies in 1986, down from 30 in 1985. Two companies did not provide peak demand data.

Breaking with a three-year rising trend, average load factor (unweighted) for the Top 100 dropped to 56.0 in 1986. It was 59.9 in 1985, 59.6 in 1984, 57.7 in 1983, and 57.5 in 1982.

System capability

The Top 100's system capability increased 2.3 percent in 1986. For the last several years, the group averaged an increase in the 4,000 to 5,000 MW range. However, in 1986, capability was expanded by approximately 11,000 MW.

Total system reserve margin, which includes both owned-reserves and firm purchase power contracts, took a turn skyward in 1986 to 24.5 percent, from 1985's 21.9 percent. System reserve hit an all-time high in 1982 of 29 percent, then had dropped at the rate of about two percentage points a year.

At the same time, owned-reserve margins decreased in 1986 to 16.9 percent, from 1985's 17.2 percent.

In its 1987 *Electric Supply & Demand* report, the North American Electric Reliability Council says growth rates for peak demand and annual energy are slightly lower than those in 1986. NERC reports that summer 1987 peak demand will be 534,000 MW and winter peak demand will be 512,000 MW.

To serve anticipated demands, NERC said utility systems are planning to increase their net capacity resources by about 80,000 MW over the 1987-1996 period, an average annual growth rate of 1.2 percent.

A recent Utility Data Institute (UDI) report warned of power shortages before the end of the century, unless the electric utility industry expands capacity substantially beyond what is currently being planned. The report predicts that installed capacity will exceed available capacity by

1997.

UDI noted that the Southeastern and South Central regions of the U.S. face the severest prospects of supply shortages. Both regions are expected to experience negative operating margins by 1993.

Also, stated the institute, the probability of shortages in the Midwest and Mid-Atlantic states by the end of the century is greater than 50 percent. The risk of power shortages in New England, most of Texas, and the West is less than 50 percent but still significant.

Done by Applied Economic Research Company for UDI, the report forecasts an average national electricity demand growth of nearly 2.4 percent annually. The amount of capacity required to meet predicted load in 1997 will be 664,000 MW, about 44 percent more than was required in 1985, said UDI.

The Edison Electric Institute is forecasting a 2.2 percent level of growth, while the National Coal Association expects a 2.0 percent growth rate. Electric utility consultant John O. Sillin, who works for Management Analysis Company, has predicted a growth rate of between 2 and 2.5 percent for 1987.

Generating capacity

Generating capacity for the Top 100 rose a modest 1.5 percent in 1986, as seen in Table 3. The share of total capacity represented by conventional steam and combined cycle capacity declined 0.3 percent. Gas turbine and internal combustion capacity also dropped. Hydro and pumped storage capacity increased, while nuclear capacity jumped 14.1 percent.

It was the fourth consecutive year that nuclear capacity increased. It rose 13.8 percent in 1985, 11 percent in 1984 and 8 percent in 1983.

The Atomic Industrial Forum says that nuclear power accounted for 17 percent of the U.S. electricity supply in 1986. UDI said in the period 1984-1987, domestic utilities have placed, or will place approximately 34 nuclear units into service. After 1987, fewer than 10 remaining nuclear units are scheduled to enter service in the U.S.

Leading nuclear utilities

The leading nuclear utilities are:

- Commonwealth Edison...8,127 MW.
- Duke Power...7,170 MW.
- Middle South Utilities...3,766 MW.
- Dominion Resources...3,141 MW.
- FPL Group...2,885 MW.

TABLE 5
SYSTEM HEAT RATE LEADERS — FOSSIL — FUELED BOILERS ONLY

Utility	Heat Rate (Btu/KWh)
1. Duke Power	9,261
2. Consumers Power	9,675
3. American Electric Power	9,730
4. Commonwealth Energy	9,735
5. Florida Power Corp.	9,776
6. Toledo Edison	9,842
7. DPL Holdings, Inc.	9,903
8. SCANA	9,904
9. United Illuminating	9,906
10. Cincinnati Gas & Electric	9,933

TYPE OF GENERATION IN THE SYSTEM

	Fossil			Hydro & Pump Storage			Diesel/Combustion Turbines			Nuclear		
Company	MW	%	Last Year Change MW	MW	%	Last Year Change MW	MW	%	Last Year Change MW	MW	%	Last Year Change MW
Allegheny Power System	7,069	89	+ 33	902	11	—	0	0	0	0	0	0
American Electric Power	19,800	87	—	836	4	—	61	1	—	2,130	9	—
Atlantic Electric	842	57	—	0	—	—	368	25	—	321	18	+ 2
AZP Group	2,431	66	- 92	6	1	—	501	14	—	739	20	+739
Baltimore Gas & Electric	2,891	53	-147	0	—	—	717	13	- 40	1,830	34	+160
Boston Edison	1,802	67	- 69	0	—	—	239	8	—	667	25	- 3
Carolina Power & Light	5,068	61	—	218	3	—	1,018	12	—	1,955	24	—
Centel	500	75	- 55	0	—	—	163	25	- 55	0	—	—
Central & South West	13,570	100	+841	0	—	—	0	—	—	0	—	—
Central Hudson Gas & Electric	902	92	+ 3	43	4	—	38	4	—	0	—	—
Central Illinois Light	1,106	93	—	0	—	—	32	3	- 2	0	—	—
Central Illinois Public Service	2,802	99	- 4	0	0	0	3	1	—	0	0	0
Central Louisiana Electric	1,681	100	+320	0	—	—	0	—	—	0	—	—
Central Maine Power	590	59	—	337	34	+ 6	45	5	+ 1	29	2	+ 29
Central Vermont Public Service	24	21	- 1	41	36	—	29	25	- 3	20	18	+ 20
Cincinnati Gas & Electric	3,555	88	—	0	0	0	475	12	—	0	0	0
Cleveland Electric Illuminating	3,508	81	+631	305	7	—	62	2	—	440	10	+440
Commonwealth Edison	9,703	49	—	624	4	—	1,331	7	—	8,127	41	—
Commonwealth Energy System	1,024	94	—	0	—	—	62	6	—	0	—	—
Consolidated Edison	6,138	68	+279	0	—	—	2,076	23	+ 1	849	9	—
Consumers Power	4,044	64	- 1	1,089	17	—	347	6	- 10	803	13	+ 14
Delmarva Power & Light	1,788	79	—	0	—	—	168	7	- 2	321	14	+ 2
Detroit Edison	7,860	87	- 30	918	10	—	525	3	—	0	0	0
Dominion Resources	6,031	54	-116	1,587	14	+ 1	439	4	-111	3,141	28	+ 6
DPL, Inc.	2,466	93	+175	0	—	—	183	7	- 27	0	—	—
Duke Power	6,393	41	-210	1,452	9	+ 30	599	4	—	7,170	46	+1,085
Duquesne Light	2,457	84	-306	0	—	—	66	3	+ 66	385	13	—
Eastern Utilities Associates	509	85	—	0	—	—	47	8	—	46	7	+ 46
El Paso Electric	833	64	- 87	0	—	—	69	5	0	401	31	+401
Empire District Electric	432	67	+ 20	16	3	—	195	30	—	0	—	—
Florida Progress (FPC)	4,175	70	- 2	0	—	—	1,083	18	—	731	12	+ 64
FPL Group (FP&L)	8,279	63	-614	0	—	—	1,924	15	- 26	2,885	22	+ 14
*General Public Utilities	4,067	49	- 62	307	4	- 38	1,487	18	—	2,334	28	—
Gulf States Utilities	5,821	89	—	0	—	—	90	1	—	655	10	+655
Hawaiian Electric Industries	1,269	85	- 5	0	—	—	221	15	+ 1	0	—	—
Houston Industries	11,332	89	+140	0	—	—	1,348	11	+164	0	—	—
Idaho Power	991	36	+ 1	1,681	62	-105	50	2	—	0	—	—
IE Industries	541	52	—	0	—	—	156	15	- 1	350	33	—
Illinois Power	3,562	95	—	2	—	—	176	5	—	0	—	—
Interstate Power	896	94	+ 1	0	0	0	55	6	—	0	—	—
Iowa-Illinois Gas & Electric	1,002	69	- 79	3	1	- 1	64	4	- 3	384	26	—
Iowa Resources	866	76	-188	0	0	0	275	24	—	0	—	—
IPALCO	2,771	97	+449	0	—	—	74	3	—	0	—	—
Kansas City Power & Light	2,037	69	—	0	—	—	370	13	—	530	18	—
Kansas Gas & Electric	1,901	78	+ 21	0	0	0	3	—	- 20	530	22	—
Kansas Power & Light	2,196	87	+ 5	0	—	—	335	13	+ 4	0	—	—
Kentucky Utilities	3,111	97	+ 21	23	1	- 2	59	2	—	0	—	—
Long Island Lighting	11,302	97	-773	0	—	—	402	3	+185	0	—	—
Louisville Gas & Electric	2,131	95	+ 2	79	1	—	108	4	—	0	—	—
Madison Gas & Electric	406	69	—	0	—	—	88	15	—	94	16	—
MDU Resources Group	347	81	- 2	0	—	—	81	19	- 5	0	—	—
Middle South Utilities	12,143	73	—	70	1	—	537	3	—	3,766	23	- 157
Midwest Energy	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Minnesota Power	1,126	91	-154	109	9	—	0	—	—	0	—	—
Montana Power	970	65	+181	520	35	—	5	—	—	0	—	—
Nevada Power	1,312	75	—	0	—	—	429	25	—	0	—	—
New England Electric	2,643	66	- 15	1,155	29	- 20	57	1	—	140	4	+140
NY State Electric & Gas	2,366	97	—	68	3	+ 3	7	—	—	0	—	—
Niagara Mohawk Power	3,532	70	-174	685	14	68	237	4	- 73	610	12	—
Northeast Utilities	2,433	38	- 52	1,269	20	- 6	461	7	- 21	2,269	35	+749
Northern Indiana Pub. Service	3,145	93	+344	10	—	0	241	7	0	0	—	—
Northern States Power	3,225	53	- 73	223	3	+ 44	1,108	18	+120	1,564	26	+ 17
Ohio Edison	4,813	89	—	0	—	—	164	3	—	425	8	—
Oklahoma Gas & Electric	5,714	99	+117	0	—	—	59	1	—	0	—	—
Orange & Rockland Utilities	902	89	—	34	3	—	74	7	—	0	—	—
Otter Tail Power	534	85	+ 28	4	1	—	87	14	—	0	—	—
Pacific Gas & Electric	8,574*	57	—	3,694	25	- 1	418	3	+ 24	2,215	15	1,016
PacifiCorp	3,122	75	+ 70	976	24	—	26	—	+ 26	30	1	+ 3
Pennsylvania Power & Light	5,785	69	—	146	1	—	539	6	—	1,890	23	—
Philadelphia Electric	2,881	37	-320	1,290	16	—	804	10	-476	2,883	37	+1,067
Portland General Electric	1,271	47	+141	601	22	—	122	4	+ 6	729	27	—
Potomac Electric Power	4,809	89	—	0	—	—	566	11	- 86	0	—	—
Public Service Enterprise Group	4,312	43	—	165	2	—	2,713	27	—	2,842	28	+1,025
Public Service of Colorado	2,458	84	+ 91	95	3	+ 10	174	6	- 13	200	7	
Public Service of Indiana	5,411	95	—	55	1	—	221	4	—	0	—	—
Public Service of New Hampshire	1,098	85	—	68	6	- 1	118	9	—	0	—	—
Public Service of New Mexico	1,286	82	+ 5	0	—	—	26	3	—	260	17	+260
Puget Sound Power & Light	858	46	+175	310	17	—	703	37	—	0	—	—
Rochester Gas & Electric	510	48	+ 77	47	4	—	29	3	—	470	45	—
San Diego Gas & Electric	1,854	69	—	0	—	—	333	12	—	517	19	—
Savannah Electric & Power	538	88	—	0	—	—	72	12	—	0	—	—
SCANA Corp.	2,374	61	+ 88	756	19	—	170	5	+ 60	590	15	—
Sierra Pacific Resources	742	89	+ 26	8	1	- 4	87	10	—	0	—	—
Southern California Edison	10,072	67	—	943	6	+ 1	1,620	11	—	2,348	16	+386
Southern Company	19,650	76	+ 64	2,591	10	- 13	1,131	4	—	2,438	10	+ 44
Southern Indiana Gas & Electric	1,032	88	+250	0	—	—	135	12	—	0	—	—
Southwestern Public Service	3,945	97	—	0	—	—	106	3	—	0	—	—
Teco Energy	2,869	95	+ 7	0	—	—	158	5	—	0	—	—
Texas Utilities	17,804	100	0	—	—	—	—	—	—	—	—	—
TNP Enterprises	0	0	0	0	0	0	49	100	—	0	0	0
Toledo Edison	1,213	71	—	0	—	—	77	4	—	421	25	—
Tucson Electric Power	1,113	84	—	0	—	—	218	16	—	0	—	—
Union Electric	5,571	72	- 9	631	8	—	386	6	—	1,109	14	—
United Illuminating	1,112	95	- 12	0	—	—	17	1	- 5	42	4	+ 42
Utah Power & Light°	3,016	95	+ 20	127	4	—	19	1	—	0	—	—
Utilicorp United	616	68	- 34	0	—	—	530	32	+234	0	—	—
Washington Water Power	344	25	—	946	68	—	101	7	—	0	—	—
Wisconsin Electric Power	3,051	70	-216	79	2	+ 72	254	6	- 9	970	22	—
Wisconsin Power & Light	1,457	77	—	43	2	+ 1	177	9	—	215	11	—
Wisconsin Public Service	1,269	73	—	56	3	—	189	11	—	217	13	—

0 Includes Geothermal capacity NA Not available * Includes combined cycle

TRANSMISSION AND DISTRIBUTION LINES IN OPERATION

Company	Transmission				Distribution							
					Overhead				Underground			
	189 kV & Up (circuit miles)	Miles Added	Below 189 kV (circuit miles)	Miles Added	22 kV & Up (pole miles)	Miles Added	Below 22 kV (pole miles)	Miles Added	22 kV & Up (cable miles)	Miles Added	Below 22 kV (cable miles)	Miles Added
Allegheny Power Systems	1,107	18	3,330	- 15	4,625	- 40	48,913	360	11	—	2,871	227
American Electric Power	5,926	80	15,783	14	4,939	915	92,074	-451	327	71	6,558	359
Atlantic Electric	64	0	1,168	2	—	—	5,964	36	—	—	766	32
AZP Group	2,398†	54†	2,295†	3†	0	—	10,589	83	0	—	6,119	427
Baltimore Gas & Electric	466	23	611	- 19	741	1	51,528△	193△	170	1	20,679	NA
Boston Edison	160	—	200	—	0	—	4,555	—	0	—	7,339	—
Carolina Power & Light	2,993	76	3,053	7	37,237*	495*	—	—	3,640*	476*	—	—
Centel	2,975*†	- 16*†	—	—	6,609*	- 46*	—	—	539*	- 92*	—	—
Central & South West	1,813	308	14,104	4,184	499	17	56,433	1,623	318	20	5,513	267
Central Hudson Gas & Electric	76	—	526	- 1	44	0	6,335	23	0	0	754	35
Central Illinois Light	47	—	283	—	615	- 11	5,601	- 8	6	- 1	1,693	22
Central Illinois Public Service	305	3	4,188	- 53	—	—	8,294	8	—	—	648	23
Central Louisiana Electric	298	0	767	0	10,710	348	—	—	737*	84*	—	—
Central Maine Power	208	—	2,003	—	263	—	16,790	—	6	—	594	—
Central Vermont Public Service	0	—	623	1	0	0	7,121	67	0	0	119	15
Cincinnati Gas & Electric	383	—	1,331	12	513	9	8,958	26	27	2	1,835	92
Cleveland Electric Illuminating	359	—	1,993	+ 52	0	—	9,491	17	0	—	5,305	123
Commonwealth Edison	2,447	—	2,444	+ 1	35,791*	55*	—	—	21,701*	577*	—	—
Commonwealth Energy System	60	0	294	0	1,505	6	3,332	33	838	48	2,191	74
Consolidated Edison	409	—	22	—	458△	20△	25,254△	-181△	6,536	106	57,991	49
Consumers Power	1,918	—	7,926	13	47,710*	253*	—	—	6,365*	180*	—	—
Delmarva Power & Light	263	—	1,090	- 1	4,807	- 3	1,759	- 1	1,935	187	784	51
Detroit Edison	565	-403	3,805	-619	0	0	29,800	139	0	0	7,179	145
Dominion Resources	2,900	17	2,942	—	38,918*	196*	—	—	13,546*	1,061	—	—
DPL, Inc.	448	—	1,339	1	NA	—	NA	—	NA	—	NA	—
Duke Power	3,056	1	9,292	62	9,198	104	47,596	538	1,948	171	3,827	310
Duquesne Light	148	0	513	4	393	- 2	6,145	37	416	9	2,155	52
Eastern Utilities Associates	179	1	186	3	2,541	3	877	4	734	66	235	13
El Paso Electric	633	0	668	14	1,370	25	3,032	34	102	8	712	14
Empire District Electric	0	—	1,225	- 2	0	—	4,722	78	0	—	228	9
Florida Progress (FPC)	1,526	8	2,104	-552	3,630*‡	—	—	—	—	—	3,546	-2,412
FPL Group (FP&L)	3,196	26	2,215	8	34,388*	591*	—	—	11,934*	833*	—	—
General Public Utilities	1,868	719	3,985	425	5,000	68	40,412	209	1,399	34	11,891	708
Gulf States Utilities	1,149	—	3,564	4	1,370	15	17,920	116	101	6	1,707	27
Hawaiian Electric Industries	—	—	1,464	3	—	—	3,835	61	—	—	2,295	20
Houston Industries	933	1	2,490	12	1,385	256	17,909	205	1,171	78	4,306	253
Idaho Power	1,481†	—	3,177†	10†	4,105	40	13,000	9	170	17	4,516	132
IE Industries	67	—	3,214	2	—	—	4,714	—	—	—	1,688	53
Illinois Power	485	—	2,351	- 4	1,334	—	14,184	-2,318	4	—	1,061	37
Interstate Power	69	—	2,501	- 67	NA	NA	NA	NA	—	—	534	12
Iowa-Illinois Gas & Electric	305	—	690	51	0	—	4,620	1,269	0	—	1,150	34
Iowa Resources	345	—	1,071	-107	—	—	11,279	31	—	—	2,248	152
IPALCO	454	33	607	- 2	0	—	4,664	12	0	—	4,021	249
Kansas City Power & Light	295	—	1,364	8	0	—	8,802	9	0	—	4,933	264
Kansas Gas & Electric	663	—	1,573	- 19	—	—	7,726	7	—	—	1,931	136
Kansas Power & Light	491	-300	3,869	283	0	—	12,368	50	0	—	450	31
Kentucky Utilities	514	- 31	4,166	- 42	0	—	14,177	126	—	—	—	—
Long Island Lighting	1,189*	—	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Louisville Gas & Electric	131	—	760	2	86	—	3,289	15	0	—	1,867	62
Madison Gas & Electric	124	—	178	1	0	—	1,075	—	0	—	623	40
MDU Resources Group	313	2	2,831	8	0	—	2,849	14	0	—	1,707	36
Middle South Utilities	2,578	2	7,453	- 18	4,644	50	65,756	452	1,621	54	3,182	221
Midwest Energy	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Minnesota Power	606†	—	1,491†	12†	745	- 1	3,883	- 18	0	—	937°	112°
Montana Power	1,445	- 4	5,393	1	—	—	12,840	22	—	—	1,129°	29°
Nevada Power	613	0	458	0	0	0	2,679	28	0	0	2,919	287
New England Electric	602	0	1,976	- 1	787	0	16,397	118	201	—	6,985	168
NY State Electric & Gas	813	-303	3,405	-381	2,053	- 39	30,432	196	1°	—	220°	—
Niagara Mohawk Power	1,116	1	8,073	7	108,065*△	226*△	—	—	6,978*	172*	—	—
Northeast Utilities	497	—	1,635	—	21,087*	-280*	—	—	5,895*	376*	—	—
Northern Indiana Pub. Service	332	—	2,653	17	0	—	7,636	16	0	—	695	37
Northern States Power	1,461	16	5,406	5	0	—	25,335	267	0	—	10,920	351
Ohio Edison	621	- 1	4,952	30	0	—	24,667	45	0	—	2,980	144
Oklahoma Gas & Electric	982	56	3,567	21	19,522*	139*	0	—	5,573*	362*	0	—
Orange & Rockland Utilities	80	—	471	—	0	—	4,673	48	0	—	981	37
Otter Tail Power	412	5	4,845	-179	149	0	802	- 28	21	0	1,483	23
Pacific Gas & Electric	4,235	—	9,819	—	93,000*	—	—	—	—	—	—	—
PacifiCorp	3,238	12	3,646	- 66	27,665*	70*	—	—	7,654*	375*	—	—
Pennsylvania Power & Light	1,308	1	0	—	2,358	25	47,761	474	14	—	7,040	327
Philadelphia Electric	733	- 1	364	—	61	—	11,702	7	18	—	15,707	490
Portland General Electric	1,038	0	929	- 12	0	—	7,977	-803	0	—	4,632	879
Potomac Electric Power	773	0	26	0	298	5	4,527	- 25	738	- 49	9,882	242
Public Service Enterprise Group	722	29	271	—	47	33	NA	—	2,023	—	23,479	—
Public Service of Colorado	1,298	23	1,606	- 34	1,139	-309	11,072	-438	215	14	4,807	486
Public Service of Indiana	1,394	—	4,003	- 5	0	—	18,221	112	0	—	2,287	84
Public Service of New Hampshire	283	—	1,458	- 29	9,652*	180*	—	—	577*	68*	—	—
Public Service of New Mexico	1,896	45	888	0	4,625	91	0	—	2,093 ø	137 ø	—	—
Puget Sound Power & Light	419†	58†	1,775†	- 55†	111	—	9,946	—	37	—	4,135	—
Rochester Gas & Electric	0	—	711	- 8	6,699*	—*	—	—	0	—	4,244	55
San Diego Gas & Electric	606	—	1,131	24	—	—	7,270	9	—	—	6,580	285
Savannah Electric & Power	39	—	62	—	292	1	2,290	38	—	—	—	—
SCANA Corp.	788	39	2,380	5	7,272	89	6,017	61	NA	NA	NA	NA
Sierra Pacific Resources	914	1	2,465	32	7,513	146	—	—	2,772	191	—	—
Southern California Edison	5,240	50	6,364	326	44,344*	-280*	—	—	168	15	44,953	2,529
Southern Company	5,779	- 1,767	19,162	-1,480	87,069*	1,120*	—	—	12,982*	1,457*	—	—
Southern Indiana Gas & Electric	0	0	829	9	0	0	3,182	2	0	0	716	24
Southwestern Public Service	1,462	88	4,018	14	14,812	103	—	—	1,178	22	—	—
Teco Energy	354	0	792	16	0	—	6,527	59	0	—	1,709•	7•
Texas Utilities	3,870	137	8,670	50	3,355	294	47,979	75	1,481	260	7,467	157
TNP Enterprises	20	0	1,585	1	—	—	8,661	594	—	—	427	51
Toledo Edison	158#	—	1,025#	- 28#	0	—	6,979	23	0	—	747	14
Tucson Electric Power	1,456	- 1	326	—	536	- 7	6,692	400	33	—	2,795	278
Union Electric	988	1	2,632	11	3,608	7	20,171	160	342	3	7,862	167
United Illuminating	118	112	106	7	2	0	3,022	0	2	0	1,094	18
Utah Power & Light	2,295	19	5,916	183	15,948*	230*	—	—	3,078*°	118*°	—	—
Utilicorp United	58†	—	1,235†	6†	0	—	4,733	16	0	—	599	73
Washington Water Power	544†	- 1†	1,498†	- 30†	595	7	8,686	- 27	0	—	1,424	165
Wisconsin Energy	686	0	1,789	5	22,215*	- 17*	—	—	8,470*	386*	—	—
Wisconsin Power & Light	107	0	2,623	- 10	—	—	16,644	-120	—	—	1,081	9
Wisconsin Public Service	124	0	1,476	- 94	17,890*	1,458*	—	—	1,497*	- 1,996*	—	—

* Total All Voltage Levels
† Pole Miles
° Conduit Bank Miles
△ Wire Miles
‡ Circuit Miles
# Lines Miles
ø Conduit and Cable Miles
• Trench Miles
NA Not available

○ Philadelphia Electric...2,883 MW.
○ Public Service Enterprise Group...2,842 MW.
○ Southern Company...2,438 MW.
○ Southern California Edison...2,348 MW, and
○ GPU...2,334 MW.

Because of reporting inconsistencies by the Top 100, summarization and trend spotting in the T&D data is next to impossible.

Largest transmission additions

Utilities with the largest additions to their high-voltage transmission systems (above 189-kV) in 1986 were:
○ GPU... 719 circuit miles added.
○ Central & South West...308 circuit miles added.
○ Texas Utilities...137 circuit miles added.
○ United Illuminating...112 circuit miles added.
○ Southwestern Public Service...88 circuit miles added, and
○ American Electric Power...80 circuit miles added.

Utilities that added the most to transmission systems below 189-kV:
○ GPU...425 circuit miles added.
○ Southern California Edison...326 circuit miles added.
○ Kansas Power & Light...283 circuit miles added, and
○ Utah Power & Light...183 circuit miles added.

Distribution additions

For overhead distribution above 22-kV, utilities showing the most growth are:
○ American Electric Power...915 pole miles added.
○ Central Louisiana Electric...348 pole miles added.
○ Texas Utilities...294 pole miles added, and
○ Houston Industries...256 pole miles added.

For lower voltage overhead distribution, less than 22-kV, the leaders included:
○ Central & South West...1,623 pole miles added.
○ Iowa-Ill. Gas & Electric...1,269 pole miles added.
○ TNP Enterprises...594 pole miles added.
○ Duke Power...538 pole miles added, and
○ Pennsylvania Power & Light...474 pole miles added.

Underground distribution

For underground distribution at voltage levels above 22-kV, the leaders were:
○ Texas Utilities...260 cable miles added.
○ Sierra Pacific Resources...191 cable miles added.
○ Delmarva Power & Light...187 cable miles added, and
○ Duke Power...171 cable miles added.

For underground distribution at voltages below 22-kV, the leaders include:
○ Southern California Edison...2,529 cable miles added.
○ Portland General Electric...879 cable miles added.
○ GPU...708 cable miles added, and
○ Philadelphia Electric...490 cable miles added.

Instructor station is the key to training simulator effectiveness

The electric power industry has placed more than 100 full-scope plant-specific operator training simulators in the past 20 years. The fidelity and degree of simulation in these training systems is a direct result of the continuing collaboration between utilities and simulator manufacturers.

This high level of cooperation has been driven by the demands of various regulatory agencies to provide the best possible training for today's conventional fossil-fired and nuclear power plant operators.

The evolution of the instructor station is an example of this collaborative process. Recognition of the demands placed on the operators as a result of the increasingly complex processes they are called upon to understand and control has placed growing emphasis on the training program. The old approach, based on training the hand, not the mind, has given way to an integrated, systematic performance-based approach to training.

Today's integrated training programs include extensive classroom study in the theory and principles of operation, coupled with hands-on simulator experience.

As the training has become more intensive, the training simulator has become more complex and the role of the instructor, as manager of the training exercise, is more and more demanding. Because of the increasing complexity of the training process, the instructor station has become increasingly important in teaching operators and assessing their ability to perform.

According to Dr. Karl Feintuch, an authority on training techniques, some of the considerations driving the design process for today's operator stations are as follows:

☐ Enhancing the instructor's capability to monitor and assess student performance.

☐ Elimination of time-consuming typed-in entries.

Typically, the instructor's station for a nuclear control room simulator is separated from the control-room environment. Here is the simulator at Northeast Utilities' Millstone I nuclear plant.

☐ Minimizing the cost and effort required to integrate future software enhancements.

The instructor must be able to easily and rapidly control the training scenario by inserting abnormal plant conditions, performing auxiliary operator functions, and monitoring the trainee's performance by using the features on the station.

Continued on page 30

Longer nuclear fuel cycles may account for declines in availability

Thomas A. Christopher
General Manager
Nuclear Services Integration Div.
Westinghouse Electric Corporation

Most power plants that adopted fuel cycles longer than 12 months so far have failed to achieve hoped-for improvements in availability. The longer fuel cycles appear to have created unanticipated challenges that may account for overall declines in availability in 1986—especially in U.S. nuclear power plants.

Currently, only the U.S. has a majority of its nuclear plants on extended fuel cycles. In the U.S. for example, 33 Westinghouse Pressurized Water Reactors (PWRs) are on 15- or 18-month cycles, while eight are on 12-month cycles (See figure 1). The great majority of Westinghouse PWRs located overseas follow 12 month cycles (See figure 2).

In an effort to obtain optimum fuel economy, Electricite de France has decided to operate its nuclear plants with enrichments equivalent to those for an 18-month cycle, but will continue with 12-month refuelings instead. It will offload only one-quarter of the core, as compared with the one-third that normally would be removed with each 12-month refueling.

In their analysis of the factors affecting the extended fuel cycle decision, utility nuclear managers assumed that there would be an increase in the length of less-frequent refueling outages because there would be more work to be done in the areas of preventive maintenance and technical specification inspections and testings.

It was predicted that this increase in outage duration would be modest and would be more than offset by the total elimination of every third refueling outage in the case of 18-month fuel cycles.

Additionally, it was believed that the equivalent forced-outage rate would not change because the effects of equipment wearout would be offset

cooldown transients.

Shorter cycles performing better

But industry data on performance to-date contains some surprises.

Historical data show that plants operating on 12-month fuel cycles, both domestically (figure 3) and abroad (figure 4), are operating substantially better than those on extended cycles. Moreover, the gap appears to be widening.

U.S. plants on 12-month cycles outperformed comparable European and Japaneses plants in both 1985 and 1986. U.S. plants with fuel cycles longer than 12 months outperformed their counterparts in Europe and Japan in 1985.

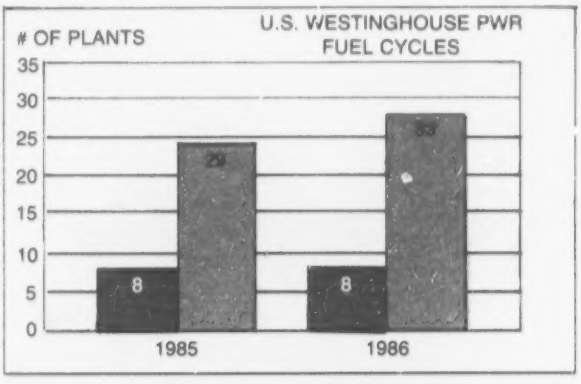
The higher overall availability of European and Japanese plants, compared with the U.S. would appear to be attributable to the much larger number of U.S. nuclear plants on fuel cycles longer than 12 months.

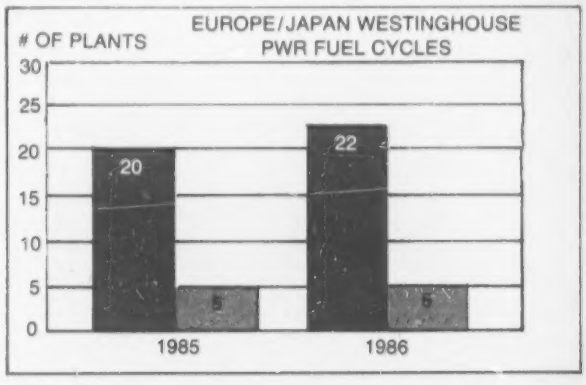
Forced-outage rates similar

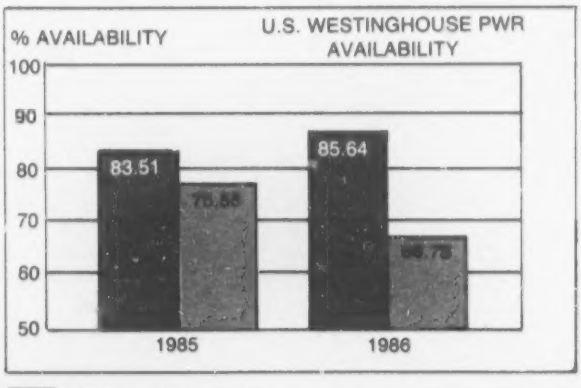
The historical forced-outage rates for long-cycle PWRs has been 15.7 percent since the TMI-2 accident, compared to 18.6 percent for 12-month cycle plants. The difference is not significant. As the recent Electric Power Research Institute report (EPRI NP-5042 Topical Report) shows, there is a high probability of outages due to break-in or startup problems in the first few months of operation, but the plants settle out and the forced-outage rate remains fairly constant through 18 months.

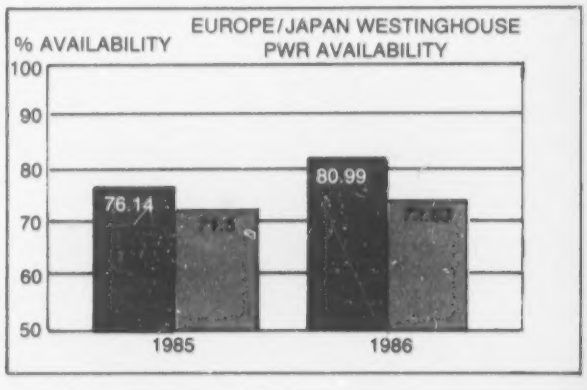
In some cases, actual refueling outage lengths have been greater than expected for long-cycle plants. Aver-

Continued on page 28









12 MO. CYCLE
18 MO. CYCLE

Shift schedules . . . from page 24

When the schedule the shiftworker is required to work does not match the characteristics of the biological clock, the worker suffers chronic biological upset and distress. Some have compared this distress to jet lag, but as people who have both performed shiftwork and travelled halfway around the world, we'll take jet lag anytime. When there is a conflict between the employees' shift schedules and their biological clocks, compromise is in order.

It is necessary to reset a shiftworker's biological clock if the worker is to be alert and useful at 3:00 a.m. This is best accomplished on a shift schedule that has been specifically designed with these factors in mind.

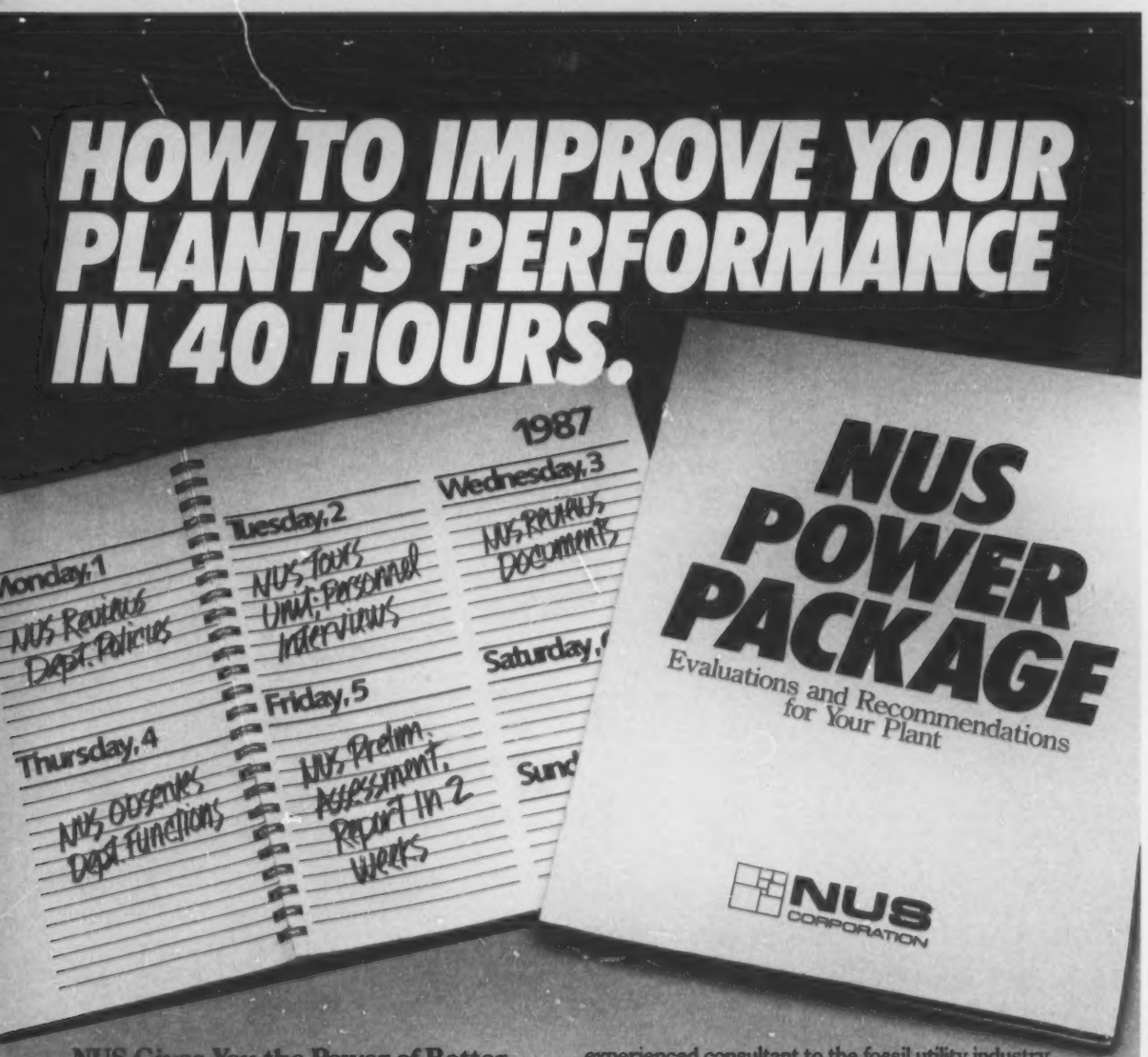
Traditionally, managements and unions have approached shiftwork problems with solutions incorporating monetary sweeteners, such as shift differentials, Sunday rates and call-back pay. Unfortunately, most shiftworkers merely pocket the money and continue to dream of a day job.

At some point, management may sense that the money is of little value. For example, the highest shift differential we have ever seen is $1 per hour. When this point is reached, a vice president is likely to ask the plant manager "what are we getting for this premium?" The answer, usually, will be "not much." The core of the problem remains the schedule and solution really lies in developing a better shiftwork program.

There are a variety of schedule models and countless variations of each model. The most common in use today was originated during World War II. It is the 28-day cycle, involving four-crew weekly rotation (often enhanced with a fifth crew for relief).

Among more modern schedules we have found several models that come much closer to matching operational needs, employee preferences and circadian rhythms. In all cases, the schedule is built around a 168-hour work week, with time-off provided within crew assignments. The three-crew, eight-hour schedule provides maximum flexibility for increased training, unlimited personal days and improved alertness. The integrated five-crew, eight-hour schedule with employee incentives for coverage reliability provides the equivalent of ten weeks vacation while reducing overtime and providing reliable manning and coverage of all functions. The 12-hour, slowly rotating schedule with a 40-hour workweek reduces built-in overtime, improves time off and is fairly easy for the employees' bodies to adjust to.

In summary, if the thought of entrusting millions—even billions—of dollars of capital facilities and equipment to a group of chronically fatigued shiftworkers is keeping you awake nights, then you should look to see if your shift scheduling doesn't need updating. You really shouldn't be operating your modern, up-to-date generating plants on a 1940-era shift schedule. There are a variety of solutions to the problem.



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Inquire R.S. 22

Longer cycles . . . from page 25

age refueling outage days for boiling water reactors (BWRs) on long cycles are 183.5, compared to 120.6 for plants on 12-month refueling schedules. But for PWRs, the long-cycle refueling outages have averaged 108.9 days, compared to 80.7 days for plants on 12-month schedules. In other words, the actual outage increase observed for some long-cycle PWRs still validates the original premise of the 18-month cycle.

The reason for the poor performance of 18-month fuel-cycle plants is other scheduled outages.

Recent analysis of Westinghouse plants' critical path days for activities directly related to refueling—reactor disassembly, fuel movement, etc.—shows that the average Westinghouse plant used 11.6 days of critical-path refueling activities in 1985, and that they increased to 20.3 days in 1986.

The actual plant-specific reasons for reduced availability vary considerably from plant to plant. The list of causes is long and complex. It also varies from year to year. The additional steam-generator availability has been overshadowed by increases in other factors.

The significant aspect of this is that there is no single overriding factor that will prevent the industry from achieving the reduction in total outage time necessary to make the extended fuel cycle decision pay off.

Improved PM needed

The challenge facing the industry will ultimately distill the need to improve all facets of plant preventive maintenance.

Clearly, standard inspection criteria for wear, percentages of system to be inspected and amounts of spares to be stocked all are variables that must be reevaluated and expanded when extended fuel cycles are utilized. New industry advances in diagnostics—for example, Westinghouse systems such as GeenAID, TurbinAID and ChemAID—can provide some much-needed intelligence.

Additionally, integrated outage management programs that focus on improved maintenance planning procedures and techniques, including critical parts analysis, have made measurable improvements in performance at plants such as Farley and Salem, among others. In summary, although current data on availability are discouraging, it is not necessarily a permanent trend. Extended fuel cycles can improve plant availability. But it will not happen automatically...nor will it be easy.